Appellants Brief Appendix Part 4

Production from the balance of Calpine's ERCOT facilities is not subject to specific contracts, although Calpine typically executes other hedges such as forward sales or other derivative transactions related to such facilities.

(ii) Texas Region Supply and Demand

ERCOT is one of the least overbuilt markets in the United States, and natural gas is almost always the price-setting fuel in the region.

(a) Supply Conditions

Load growth, retirement, and mothballing of uneconomic plants and lower levels of investment in new generation have improved the balance between supply and demand over the past few years in ERCOT. Over thirteen gigawatts ("GW") of capacity, consisting of mostly inefficient, steam-gas-fired plants, has been retired or mothballed in ERCOT. ERCOT's reserve margin is projected to continue to decline in the near term as load grows and fewer new plants are constructed.

Like California, ERCOT's current generation supply is weighted towards natural gas-fired technologies. But unlike California, coal-fired generation provides the bulk of ERCOT's baseload capacity.

The regional supply mix fosters a market in which gas-fired units set prices during most hours. The supply mix also highlights a challenge for combined-cycle plants in ERCOT. When electricity demand is sufficient to require generation only from a portion of the market's intermediate gas-fired capacity with similar variable costs, competition among combined-cycle plants to secure customers can be significant.

(b) New Coal Construction in ERCOT

The combination of decreasing reserve margins and historically high natural gas prices has stimulated increased interest in the construction of new coal-fired generation in ERCOT. Competitors such as TXU Corporation, NRG Energy, LS Power Group, CPS Energy (San Antonio), and PNH Resources have announced more than eleven GW of coal-fired additions that are targeted to reach commercial operations starting in 2009. Not all of these projects are deemed likely to succeed and some developers have recently cancelled some of their announced projects, but those that are built will affect market conditions by reducing the portion of hours during which higher-priced gas-fired units are required to satisfy load.

(iii) Texas Region Regulatory Issues

(a) Market Structure

ERCOT's current market design includes a bilateral market, a balancing energy (real-time) market, ancillary services markets, and zonal price differentiation. Certain changes to the ERCOT market structure are expected within the next few years. By January 1, 2009, ERCOT expects to move to a nodal market structure. While much is currently uncertain about the nodal design, moving to a nodal market generally is expected to improve price discovery, relieve congestion, and more clearly signal the locations of needed transmission and generation investments. In anticipation of nodal pricing, ERCOT has committed to reduce major transmission congestion through a number of transmission upgrades. By enabling the flow of electricity from high supply areas to high demand areas, these upgrades are expected to reduce the price separation that might otherwise occur under the nodal market structure. Additionally,

the introduction of a day-ahead energy market operated by an ISO will accompany the introduction of nodal pricing. Under a day-ahead market, participants submit bids to the ISO. If bids are accepted, operators know their units will be called to produce electricity. This market will provide market participants with an alternative to bilateral arrangements, which currently dominate the ERCOT market.

The Public Utility Commission of Texas recently approved a new measure to address the possibility of market power abuse (*e.g.*, withholding production, predatory pricing, or collusion) in the ERCOT market. While the details are yet to be determined, members of ERCOT that own more than 5% of the installed generation base, such as Calpine, likely will offer voluntary mitigation plans to the Public Utility Commission of Texas for consideration.

In contrast to California as well as the Northeast markets, Texas legislators have voiced commitment to an "energy only" approach to ensuring system reliability. Rather than creating a separate payment mechanism for capacity, energy only resource adequacy programs count on adequate compensation from variable energy prices to motivate sufficient levels of generation construction. Energy only programs typically feature high or nonexistent price caps. ERCOT's plan is to increase the energy offer cap from the current $1,000 per MWh to $3,000 per MWh, shortly after the nodal market is implemented.

(b) Environmental Issues

While environmental issues are not heavily regulated in ERCOT, more stringent NO_x emissions regulations are on the horizon. As of March 31, 2007, power generation facilities became subject to daily and thirty-day emission restrictions under Houston-area rules specified by the Texas Commission on Environmental Quality, and allocations under the Houston-Galveston Mass Emission NO_x cap-and-trade program will decline starting in 2008. Further, the proposed eight-hour Ozone State Implementation Plan, which requires installment of increased NO_x controls in eastern Texas, is scheduled to be complete by June 2007 with mandated controls likely to start in 2010. Finally, as discussed, CAIR will cap NO_x and SO_2 emissions in twenty-nine of the easternmost states, including Texas, starting in 2009. While the changes will affect all plants located in Texas, especially coal plants, they are particularly pertinent to Calpine's Houston-area assets.

The oldest units in the ERCOT fleet, Texas City and Clear Lake, will be subject to all four changes. Calpine has retrofitted one of its Texas City units to meet environmental standards and will retrofit one of the remaining two units to avoid decreased run times starting in October 2007. There is no plan to retrofit the third unit because there is no projected need to run that unit more than the level to which it will be restricted in the future. Calpine has yet to retrofit any of the three units at Clear Lake.

d. <u>Southeast Region</u>

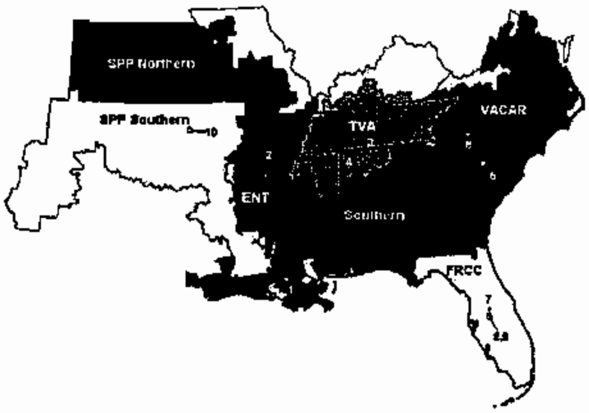
(i) Southeast Region Assets

(a) Plants

After the divestiture of certain facilities (including Hog Bayou, Acadia, Santa Rosa, and Pryor), Calpine expects to operate ten gas-fired plants in the Southeast region (Alabama, Arkansas, Florida, Louisiana, Oklahoma, and South Carolina) with a total capacity of 5,835 MW, which includes 2,350 MW from cogeneration facilities that market steam in addition to electricity and often are required to run during uneconomic hours to maintain steam output. Calpine defines the "Southeast" as the markets of the Southeastern Electric Reliability Council ("SERC"), the Florida Reliability Coordinating Council ("FRCC"), and the Southwest Power Pool ("SPP"), located to the north of ERCOT. SERC spans an area

of approximately 460,000 square miles over thirteen states. Calpine has plants in three sub-regions within SERC: Entergy; Tennessee Valley Authority; and the Virginia and Carolinas Regional Group ("VACAR"). Calpine's plants in the southern sub-region of SERC are slated for divestiture and thus, this section does not contain a discussion of that region. The FRCC region includes the majority of the state of Florida. SPP encompasses all or part of six states in the South-Central United States, including Oklahoma.

Calpine's Southeast region plant location and technology types are illustrated below.



Source for map: Energy Velocity

Plant	Location	In Service Year	Capacity[1]	Contract Status
Operating			6,835	
SERC-Entergy			718	
Intermediate - Cogen				
1 Carville	Saint Gabriel, LA	2003	519	Partial
2 Pine Bluff	Pine Bluff, AR	2001	199	Partial
SERC-TVA			[illegible]	
Intermediate				
3 Decatur	Decatur, AL	2002	817	Partial
Intermediate - Cogen				
4 Morgan	Decatur, AL	2003	658	Partial
SERC-VACAR			1,487	
Intermediate - Cogen				
5 Columbia	Calhoun County, SC	2002	620	Partial
Peaking				
6 Broad River	Gaffney, SC	2000	866	Full
FRCC			868	
Intermediate				
7 Osprey	Auburndale, FL	2004	595	Partial
Intermediate - Cogen				
8 Auburndale	Auburndale, FL	1994	153	Partial
Peaking				
9 Auburndale Peaker	Auburndale, FL	2002	120	Partial
SPP			1,087	
Intermediate				
10 Oneta	Broken Arrow, OK	2002/2003	1,087	None

[1] Modeled average annual operating capacity in MW.

(b) Contracts

Certain of Calpine's Southeast region plants are subject to contracts that dictate the payments Calpine receives for energy and capacity sold from the plants. The cogeneration facilities are subject to power and steam sales agreements with industrial companies. Total steam contract obligations in the Southeast create must-run obligations for approximately 200 MW. Also, long-term power sales agreements reduce the market price risk of the Decatur and Osprey combined-cycle facilities and the Auburndale and Broad River peaking plants.

Calpine continues to pursue other opportunities to secure long-term contracts in the Southeast region, which are viewed as preferable to pure merchant operation, assuming fair contract pricing.

(ii) Southeast Region Supply and Demand

Most regions of the Southcast are considerably more overbuilt than California and ERCOT, and coal is often the price-setting fuel. The VACAR sub-region of SERC is an exception. Lowcr reserve margins in VACAR suggest market recovery (when supply and demand come into balance) in 2011. These factors, combined with the dominance of incumbent utilities, contribute to a challenging market climatc for merchant gas-fired plants.

(a) SERC-Entergy

Reserve margins in certain SERC sub-regions currently are among the highest in the nation. These excess supply levels were caused in part by merchant generation investments in the early part of the decade, but the legislative climate also contributes to these excess supply levels by discouraging plant retirements. Grandfathered transmission rights essentially guarantee preferred transmission access for life and provide a signifieant ineentive to prolong the life of certain existing facilities.

Many older plants in SERC would be less likely to operate economically in an unencumbered competitive market, especially given pending environmental legislation. If these units are retired, reserve margins will improve, although many years are expected to pass before demand catches up to supply.

In spite of the fact that 69% of Entergy's supply is gas-fired, excessive reserve margins mean that gas-fired units often are not required to meet electricity demand. Instead, prices are often set by coal-fired plants, leading to lower power prices and negative spark spreads during many hours.

(b) SERC-TVA

Excessive supply also adversely affects Calpine's Morgan and Decatur plants in the TVA sub-region of SERC. The reserve margin is expected to remain high due to new capacity construction already in progress, including 1,300 MW of nuclear capacity through the restart of the Brown's Ferry faeility in 2007.

TVA's fleet is heavily weighted toward baseload generation, including coal (43%), hydro (16%), and nuclear (13%).

(c) SERC-VACAR

As stated, the VACAR sub-region is the least overbuilt within SERC. Load growth is expected to create the need for new plant eonstruction by 2011, assuming certain uneconomic units retire as anticipated. Current VACAR capacity is weighted heavily toward baseload generation. Coal and nuclear generation account for more than 90% of the electricity produced in the region. Announced construction projects suggest that coal is the fuel of choice for new generation, but the superior operational flexibility of gas-fired units will be needed to serve demand swings.

(d) FRCC

Significant long-term contracts mitigate Calpine's exposure to Florida's excess supply conditions. FRCC's reserve margin is projected to decrease in the coming years due to load growth and minimal net supply capacity changes. Plans for several new plants have recently been announced, including three GW of coal-fired generation, although these projects face local opposition.

(e) SPP

SPP is a fragmented regional market due to transmission constraints that create multiple pockets of isolated load and generation. By limiting the delivery of power from production areas to load areas, these constraints have slowed the growth of a competitive wholesale market. However, anticipated transmission upgrades in the region as well as tightening reserve margins may begin to counter this problem. Most notably, the Tulsa Loop transmission upgrade project, due to be completed late in 2007, is expected to alleviate most of the congestion into Tulsa.

(iii) Southeast Region Regulatory Issues

Relatively little progress has been made toward restructuring the electricity markets of the Southeast. In contrast to more developed competitive markets, the Southeast markets are characterized by various inefficiencies. First, local utilities have not been compelled to divest their generating assets or to procure electricity from third parties. Consequently, these entities dominate the large load pockets and exert control over the transmission system. Also, market participants are dependent on bilateral market transactions with relatively few counterparties. SERC and FRCC have not adopted an ISO or Regional Transmission Organization to help facilitate a transition towards competitive electricity markets. SPP is the exception. SPP was granted Regional Transmission Organization status in 2004 and is in the process of implementing a balancing market in 2007. Lastly, regulations protect older generating units that are less efficient and would otherwise face retirement.

Two notable examples of the limitations on competition created by the political strength of incumbent utilities are grandfathered transmission rights in Entergy and barriers to new merchant plant construction in Florida. Grandfathered transmission rights in Entergy effectively limit transmission access and create an aging fleet of utility-affiliated generators. Local utilities continue to exert significant control over the transmission system. FRCC's Florida Electric Power Plant Act of 1996 also has essentially prevented out-of-state power producers from building plants in peninsular Florida without first obtaining a contract for the plant's output.

While there are no plans to change the market structures of SERC and FRCC, SPP began a node-based imbalance market in February 2007. The employment of a nodal pricing mechanism will improve price discovery in SPP, which will in turn help motivate more efficient economic behavior. Over time, it is hoped that price signals will drive generation and transmission investment to congested areas, thereby alleviating some of the fragmentation that has historically restricted the growth of competition in the SPP market.

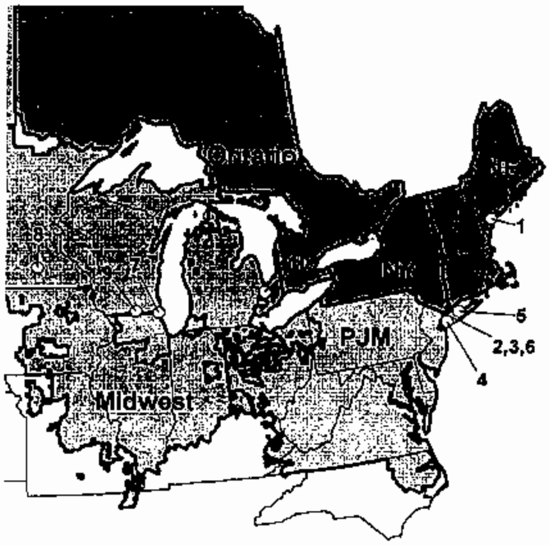
e. <u>Northeast/Midwest Region</u>

(i) Northeast/Midwest Region Assets

(a) Plants

Following certain divestitures, Calpine expects to operate nine gas-fired plants with a total capacity of 2,296 MW in its Northeast/Midwest region, which includes 158 MW from cogeneration facilities that market steam in addition to electricity. Calpine defines this region as the markets of New York, New England, PJM Interconnection ("PJM"), and the Midwest.

Calpine's Northeast/Midwest region plant location and technology types are illustrated below.



Plant	Location	In Service Year	Capacity[1]	Contract Status
Operating			2,295	
New England			[illegible]	
Intermediate				
1 Westbrook	Westbrook, ME	2001	531	None
New York			[illegible]	
Intermediate			133	
2 Bethpage	Hicksville, NY	1989	54	None
3 Bethpage 3	Hicksville, NY	2005	79	Full
Intermediate - Cogen			158	
4 Kennedy (KIAC)	Jamaica, NY	1995	114	Partial
5 Stony Brook	Stony Brook, NY	1995	44	Partial
Peaking				
6 Bethpage Peaker	Hicksville, NY	2002	48	None
PJM			[illegible]	
Peaking				
7 Zion	Zion, IL	2002	492	Partial
Midwest			[illegible]	
Intermediate			935	
8 Mankato	Mankato, MN	Jun-05	359	Full
9 Riverside	Beloit, WI	2004	576	Full
Under Construction			503	
Ontario, Canada			503	
Intermediate				
10 Greenfield[3]	Greenfield, Ont.	2008	503	Full

[1] Modeled average annual operating capacity in MW.
[2] Excludes Calpine's 22-MW Philadelphia Water District plant, which is not currently operational
[3] Calpine will own 50% of the 1005 MW Greenfield plant.

(b) Contracts

A significant portion of Calpine's capacity in these markets is subject to long-term contracts, which dictate the payments Calpine receives for energy and capacity sold from certain plants. The Kennedy and Stony Brook cogeneration facilities are subject to power and steam sales agreements with the John F. Kennedy International Airport in Queens, New York and the State University of New York at Stony Brook, respectively. Additionally, long-term power sales agreements reduce the market price risk of all facilities in PJM and the Midwest, as well as certain plants in New York. In many cases, these contracts were secured in advance of construction.

(ii) Northeast/Midwest Region Supply and Demand

(a) New England

Calpine's Westbrook facility in New England is not subject to long-term contracts, making merchant market conditions critical to its performance. Aggressive combined-cycle construction in New England in the early part of the decade helped create overbuilt conditions in much of New England by 2004. Decreased generation investment and load growth in recent years have reduced reserve margins and contributed to some recovery of power prices and spark spreads. ISO-New England's overall reserve margin is 21%, but the supply and demand balance differs substantially by zone. Excluding imports and exports, the reserve margin in Boston is negative 27%, thus creating the need for substantial imports, while the state of Maine (where Westbrook is located) has a 71% reserve margin.

Due in part to the wave of gas-fired construction, natural gas- and oil-fired assets dominate the New England Power Pool, together accounting for approximately 63% of the capacity and 46% of the energy produced. This natural gas and oil capacity sets prices 88% of the time, with natural gas alone on the margin in 80% of all hours. This near-constant presence of natural gas or oil on the margin contributes to high electricity prices.

(b) New York

There are relatively tight supply conditions in transmission-constrained New York City and Long Island. Because wholesale electricity and capacity prices are determined on a zonal level, prices in New York City and Long Island tend to be higher. Two key drivers will affect future available supply. First, transmission projects such as the Cross Sound Cable, which establishes an interconnection with the New England Power Pool grid in Connecticut, are expected to open the markets to lower-priced generation imports from surrounding regions, thereby exerting downward pressure on prices and spark spreads. Second, the expiration of an expedited permitting process for new construction may make development more difficult. Gas-fired generators tend to set power prices during most hours in New York City and Long Island.

(c) PJM

Calpine's capacity in PJM is contracted through 2012, minimizing the impact of merchant market conditions. The expanded PJM market has a diverse generation mix with a significant portion of low-cost nuclear and coal generation. Coal dominates the baseload generation and accounts for 59% of the total energy produced. The significant amount of coal-fired and nuclear generation makes it difficult for gas-fired generation to compete during off-peak hours. Consequently, capacity factors for intermediate and peaking units tend to be relatively low.

(d) Midwest

The bulk of Calpine's capacity in the Midwest is subject to long-term contracts. The Midwest ISO region ("MISO") includes a large market footprint with transmission-isolated areas primarily in Minnesota and Wisconsin. MISO has significant levels of installed coal capacity, particularly in its Eastern areas, and new coal development projects have been announced. The resulting high percentage of hours with coal on the margin contributes to lower capacity factors for gas-fired units in the eastern reaches of MISO.

(iii) Northeast/Midwest Region Regulatory Issues

(a) Market Structure

The Northeast and Midwest markets are considered among the more developed markets in the United States. These markets have transitioned to ISO-governed structures with competitive, transparent pricing. New England, PJM, and MISO have implemented nodal pricing while New York has implemented zonal pricing. In addition, the Northeast markets have implemented distinct capacity markets in addition to energy markets.

New England, New York, and PJM have implemented capacity markets to motivate investment in levels of generation that are adequate to ensure system reliability. New England's Forward Capacity Market is designed to encourage entry of new supply, as well as to promote conservation and efficiency. After the ISO determines the level of installed capacity required for a given commitment period, resources are committed forty months in advance. An annual forward capacity auction is held for these resources and the market capacity price is pegged to the lowest priced new capacity available to meet demand requirements. Also, New York's installed capacity market links capacity prices to the supply and demand balance and the cost of new capacity construction. LSEs in both markets are required to purchase adequate capacity to cover expected load obligations. New York City and Long Island remain the most capacity-constrained areas in New York. PJM's Reliability Pricing Model replaces the current Capacity Credit market.

(b) Environmental Issues

In addition to complying with federal restrictions on SO_2, NO_x, and mercury emissions, generators in select Northeast states are preparing for additional state-specific mercury emissions regulations as well as carbon abatement measures mandated by the Regional Greenhouse Gas Initiative.

A growing list of states have adopted state-specific, mercury-specific emissions plans. Consequently, in addition to the federal CAMR obligations, coal plants in the Northeast/Midwest regions will have further mercury emission reductions to achieve. Massachusetts, Connecticut, New Jersey, and Wisconsin have already implemented their own plans and several other states have proposals outstanding. These more stringent standards, which specify aggressive 85% to 90% reductions by 2008 in Connecticut, Massachusetts, and New Jersey and 45% reductions in Wisconsin, present a significant competitive challenge for coal producers in these states.

In December 2005, seven northeastern states signed a memorandum of understanding to implement regional carbon emissions reduction measures. Since then, two other northeastern states have joined the Regional Greenhouse Gas Initiative. Although carbon allowance allocation programs are yet to be determined by most states, the program institutes a regional emissions cap in 2009, which becomes more restrictive over time.

f. Canadian Operations

Calpine's prepetition operations include certain Canadian entities also engaged in the generation and sale of power and power-related products. Simultaneously with the filing of the Chapter 11 Cases, the Canadian Debtors filed for creditor protection under the CCAA in the Canadian Court. The Debtors have been actively monitoring the CCAA Proceedings to ensure that their interests in those proceedings are protected. *See* Article III.D.6 for further information regarding the CCAA Proceedings.

3. Power Operations

a. Overview

Calpine's Power Operations group manages its fleet of power generating assets and focuses on continuous improvement of its clean, safe, efficient, and cost-effective operations. These goals are achieved by maximizing the availability and reliability of Calpine's existing fleet, leveraging Calpine's institutional expertise to optimize operations, and developing and executing selected growth plans based on Calpine's corporate and regional strategies.

Power Operations oversees Calpine's asset growth and development strategy. Calpine continually evaluates growth and development projects, focusing on opportunities that will enhance and stabilize cash flow and that are consistent with Calpine's regional development strategies. Development opportunities are selected based on a variety of factors, including regulatory environment, plant economics, technology alternatives, transmission interconnection capacity, and compatibility with existing operations.

b. Plant Management and Monitoring

Calpine operates one of the most efficient gas-fired fleets in North America. This efficiency is attributable not only to Calpine's newer turbine technology, but also to its expertise in operating and maintaining its assets. Calpine's plant management personnel oversee the day-to-day operations of the

plants, ensuring the reliability and availability of the fleet. In addition, Calpine has an active program to monitor and maintain its fleet of turbines, generators, and other major equipment.

Plant management is supported by Calpine's fleet analytics and the Turbine Maintenance Group to operate the plants efficiently and to minimize down time. Calpine's fleet analytics team provides a necessary and critical link between the financial and commercial operations in defining, measuring, and modeling plant operational performance. The fleet analytics team provides upstream analysis of future efficiency programs as well as downstream monitoring and validation of engineering optimization programs and their relationship to financial performance.

In addition, Calpine's Turbine Maintenance Group works directly with the plants, providing processes and procedures for necessary turbine maintenance. The Turbine Maintenance Group works to determine optimal turbine maintenance schedules, provides in-house expertise and services for the plants, and coordinates the use of third-party resources to implement repairs. The Turbine Maintenance Group also serves as Calpine's centralized resource for negotiating and implementing turbine-related parts and service contracts.

The ability to monitor and manipulate key operating data from the power plants is a powerful management tool. Calpine maintains a fleet-wide data acquisition, retrieval, and storage system that is secure, effective, and reliable. Calpine recently implemented a new condition-based maintenance program that evaluates the current status of its turbine fleet based on frequent inspections and operating conditions to determine the most efficient timing to replace worn parts. Calpine is further developing and enhancing its plant monitoring systems to provide an advanced fleet-wide management tool that will integrate all plant natural gas, steam, and power volumes into a common system to handle reporting, billing, monitoring, and billing disputes in a Sarbanes Oxley-compliant manner.

c. Fleet Optimization

In addition to managing and monitoring the fleet, Power Operations focuses on achieving continuous operational improvements. Utilizing its employees' knowledge and expertise, Calpine has developed a number of operating initiatives that are expected to enhance operating efficiency while decreasing operating expenses.

In particular, Calpine optimizes its fleet reliability by first targeting key areas for improvement and ensuring that a root cause analysis has been conducted for events that limit output or availability. The next step is to develop and implement maintenance programs and to design changes and failure pattern recognition programs to avoid failure incidents and limit damage and downtime. The analysis of fleet statistics provides guidance on prioritization of each of the initiatives and improvement strategies. Calpine has undertaken two key initiatives to accomplish its operational goals. First, the Performance Optimization Program focuses on enhancing the total efficiency of Calpine's plants, and primarily entails the implementation of best practices gathered from across Calpine's fleet to ensure that all plants are performing at their optimal level. Second, the Calpine Engine Optimization initiative is designed to reduce heat rates and increase the power output of Calpine's natural gas turbine fleet through implementation of optimized parts and components.

d. Growth and Development Opportunities

Calpine's Power Operations is also responsible for Calpine's growth and development efforts. All new development projects, as well as expansions of existing projects, are evaluated based on a variety of factors to determine the optimal expansion opportunities for Calpine's fleet. These factors include availability of long-term power sales and steam contracts that will provide revenue stability and allow for

non-recourse project financing, existence of a partner that will supply either financial strength or fuel supply to the project, market location, and whether the project presents the opportunity to develop at least 250 MW. Additional factors include regulatory environment, plant economics, technology alternatives, transmission interconnection capacity, and compatibility with existing operations. Calpine is currently pursuing three development and construction opportunities: Otay Mesa, Russell City, and the Greenfield Energy Centre. These growth and development opportunities are also reflected in the consolidated projected operating and financial results (the "Projections") accompanying the Disclosure Statement.

Otay Mesa. The 596 MW Otay Mesa Energy Center ("OMEC") is a gas-fired combined-cycle power project in the early stages of construction located in southern San Diego County, California. Commercial operations are expected to commence by May 1, 2009, based on a recently negotiated full toll power purchase agreement with San Diego Gas & Electric Company ("SDG&E") and certain other related agreements, under which OMEC will sell power to SDG&E for a ten-year period. Project financing and the SDG&E transaction closed in May 2007 prompting mobilization of a construction force on the site. Calpine expects to contribute approximately $55 million in equity to the construction of OMEC in 2007.

Russell City. Russell City Energy Center LLC ("Russell City") is a proposed 596 MW, gas-fired, combined-cycle plant to be located in Hayward, California. Calpine and PG&E executed a letter of intent on March 30, 2006, pursuant to which (i) Calpine and PG&E agreed to enter into a ten-year tolling arrangement under which PG&E would have the right to the full output of the plant over the term; and (ii) Calpine was required to transfer 35% of its interest in Russell City to an unaffiliated third party. To comply with the letter of intent, during the Chapter 11 Cases, Debtors sold a 35% interest in the project to Aircraft Services Corporation (an affiliate of General Electric Capital Corporation) and retained the remaining 65% interest in the project. Pursuant to the sale, Aircraft Services Corporation is obligated to, among other things: (i) fund approximately $44 million of equity in the project; (ii) provide a $37 million letter of credit required under a third party agreement; and (iii) afford Russell City the right to repurchase Aircraft Services Corporation's interest in the project under certain stated conditions. The remaining funding for development and construction of the proposed plant is expected to be provided by project financing. The total cost of the project is estimated to be $620 million.

Greenfield Energy Centre. The 1,005 MW Greenfield Energy Centre ("Greenfield") is a gas-fired, combined-cycle plant located in Courtright, Ontario, Canada. The project is currently owned by a limited partnership between an indirect wholly owned, non-Debtor subsidiary of Calpine and a subsidiary of Mitsui & Co., Ltd., each Entity owning 50% of the project. Greenfield is party to a Clean Energy Supply Contract, under which it has agreed to sell 100% of its output under a twenty-year PPA to the Ontario Power Authority. Commercial operation is expected to begin by March 2008. The Calpine/Mitsui partnership expects to raise non-recourse project debt to finance the construction costs of approximately C$528 million (approximately $470 million). Total project costs are estimated to be C$152 million (of which Calpine is obligated for one-half) for excluding any estimated contingency. Calpine closed financing on the project in May 2007.

4. Commercial Operations

a. Overview

Calpine's Commercial Operations group, which operates through Calpine Energy Services, L.P. ("CES"), manages the gross margin of Calpine's portfolio of physical and contractual assets and obligations. Commercial Operations focuses on the effective management of commodity risk exposures that affect Calpine's financial performance and the optimal dispatch of Calpine's asset portfolio.

Calpine's significant natural gas-fired portfolio makes Calpine one of the single largest consumers of natural gas in North America. This creates natural risks and opportunities for Calpine as it manages its fleet of power generation assets. During the past five years, there has been a fundamental shift upward in natural gas prices and an increase in near-term price volatility. Commercial Operations manages this dynamic by creating new products and services that take advantage of Calpine's core knowledge of natural gas as well as its economies of scale in handling such large volumes of natural gas.

To manage price risk effectively, Commercial Operations is active in trading and marketing power, fuel, transmission (power) and transportation (fuel), fuel storage, emissions allowances, and RECs in each of Calpine's core geographical regions. Trading and marketing staff work closely with operations staff to ensure plant operational characteristics are considered in the overall management of the portfolio.

Calpine's Commercial Operations' goals are to: ensure the optimal dispatch of Calpine's generating assets; reduce the potential negative impact of commodity price risk on the value of Calpine's assets and contracts; create value by using the flexibility of Calpine's physical assets, energy market competencies, and infrastructure to provide energy market participants with energy supply and management products; and generate incremental value through active portfolio management and energy marketing by leveraging Calpine's information, infrastructure, and intellectual capital as a major operator in its core markets.

Commercial Operations markets a full suite of products and services to meet its goals. These include management of commodity risk through trading structured products in bilateral and exchange-traded markets, origination of structured products for third-parties, fuel supply and power transmission arbitrage, identifying economic dispatch opportunities for the physical assets, and engaging in real-time trading and marketing of energy products and ancillary services.

b. Key Commercial Activities

Calpine recognizes that leveraging its infrastructure and expertise can create value by actively managing Calpine's commodity risk exposure while also providing value-added structured products and services to the marketplace.

(i) Economic Operation of Assets

The primary focus of Commercial Operations is to manage the fuel requirements and output of Calpine's fleet in volatile physical markets to capture targeted plant gross margins. Commercial Operations' participation in and knowledge of the physical markets also creates this opportunity to capture additional margin.

Day-to-day economic dispatch activities include: negotiation and administration of commodity-related contracts; scheduling and optimal dispatching; procurement; active management through trading; origination; fuel supply arbitrage; transmission arbitrage; and real-time trading.

(ii) Risk Management

Calpine seeks to preserve and enhance expected gross margins, but faces challenges in this regard because of price volatility in commodity markets and the fact that its plants' fuel requirements and power sales are not subject to contracts in all instances. Moreover, multiple factors such as electricity demand, natural gas prices, and Northwest hydro levels are major drivers of financial results and are each affected by unpredictable weather conditions.

During the Chapter 11 Cases, Calpine has refocused its commercial operations on managing the commodity risk exposure of Calpine's portfolio within overall capital structure and financial performance objectives. In particular, Calpine has improved its risk management policy. Through Calpine's strategic hedging efforts, Calpine executes risk management strategies to deliver expected value, stabilize commodity net margins, enhance working capital liquidity, and deploy collateral efficiently. Calpine manages commodity risk exposure by monitoring its portfolio's financial sensitivity to changing spark spread values versus changes in regional market heat rates and commodity prices to determine strategies and transactions that optimally hedge gross margin.

To deliver gross margin and manage commodity risk, Calpine analyzes both the short-term and long-term effects of decisions on Calpine. In the short-term, Calpine's commodity risk is managed within the limits defined in Calpine's Risk Policy. Maximizing the option value of the portfolio and delivering target gross margins within the risk limits requires smart trading, insightful hedging, and creative origination supported by analytics and other corporate functions.

For the long-term (*i.e.*, beyond twenty-four months), Calpine's senior management team reviews and approves long-term strategic actions. Long-term strategies generally seek to balance Calpine's market view of commodity prices and the economic value Calpine is seeking to capture with the perceived impact on the Calpine risk profile by Calpine's investors and rating agencies and the cost of implementing that strategy for Calpine's collateral and capital structure.

Activities to manage risk include: hedging spark spread value to lock in expected gross margins with a variety of physical, financial, and structured products; entering into tolling contracts that guarantee capacity payments or heat rate contracts that guarantee a fixed ratio between gas and power; transacting fixed-price capacity sales to hedge capacity values in markets where secondary capacity markets exist, such as New York; transacting in RECs or emissions credits to hedge The Geysers and emissions costs, respectively; transacting in financial and physical storage, transmission, and other time or basis hedges; and entering into hedges to manage exposure to weather uncertainty that drives demand. Tolling contracts are physical natural gas supply and power sales agreements under which the buyer of the generating capacity makes fixed and variable payments in return for the right to provide natural gas and receive power from a power plant. Tolling contracts substantially mitigate the commodity price risks of the plant operator.

Commodity risk exposure is managed within the value at risk limits defined in Calpine's Risk Policy, which Risk Policy governs the amount of risk that Calpine is willing to take in its entire portfolio.

(iii) Value Creation Through Customized Products

Calpine is naturally suited to provide customized energy products and services to other market participants. Tailored products include services in addition to the energy commodities themselves, such as steam sales, load-following contracts, and ancillary services.

Two customized product business lines that Calpine plans to continue to pursue are Energy Management Services for other energy market participants and Producer Services to natural gas producers and consumers. Calpine markets Energy Management Services to energy market participants, including producers, generators, financial institutions, and industrial consumers, by leveraging the commercial operations' infrastructure and intellectual capital. These services include trading, fuel supply, bundling of power and natural gas needs, scheduling, dispatch, and financial settlement activities. Revenues are created from service and incentive fees. With respect to Producer Services, Calpine manages up to 600 Bcf of natural gas per year and intends to leverage its market presence and intelligence by continuing to offer services to natural gas producers and purchasers. These third-party services include the aggregation

of production for producers to market their output, natural gas storage or transportation needs, and the purchase of power.

5. Regulation

a. Regulation of Electricity

Until the mid- to late-1990s, the electric power industry was dominated by vertically integrated regulated utilities, which sold power to customers at cost-based rates determined by regulatory processes. Market structure changes over the past several years have led to the development of competitive wholesale power markets in which competitive bidding sets energy prices. Power plants may now be owned by Entities other than utilities, which, like Calpine, are "merchant" generators. Merchant generators may sell electricity to utilities under specific power contracts or they may buy and sell electricity in the wholesale market. Power prices that utilities charge customers remain regulated in many regional markets, but prices in the wholesale electricity market are now largely unregulated. Consequently, Calpine's financial performance is affected by prices set by competitive forces.

Though wholesale energy pricing markets largely have been deregulated, electric utilities with whom Calpine does business historically have been, and continue to be, highly regulated at the federal, state, and local levels.

(i) Federal Regulation

There are two principal pieces of federal legislation that have governed public utilities since the 1930s: The Federal Power Act ("FPA") and The Public Utility Holding Company Act ("PUHCA") of 1935. These acts have been amended and supplemented by subsequent legislation, including PURPA, the Energy Policy Act of 1992, and the EPAct 2005. Many of the changes made by the EPAct 2005 recently have been implemented or are currently in the process of being implemented through new regulations.

Under the FPA, FERC has jurisdiction over, among other things, the disposition of FERC-jurisdictional utility property, authorization of the issuance of securities by public utilities, and regulation of the rates, terms, and conditions for the transmission or sale of electric energy at wholesale in interstate commerce. The majority of Calpine's generating projects are or will be owned by exempt wholesale generators ("EWGs"). Other than its EWGs located in ERCOT, Calpine's EWG affiliates are or will be subject to FERC jurisdiction under the FPA.

Under the FPA and FERC's regulations, the wholesale sale of power at market-based or cost-based rates requires that the seller have authorization issued by FERC pursuant to a FERC-accepted rate schedule or tariff. FERC grants market-based rate authorization based on several criteria, including a showing that the seller and its affiliates lack (or have properly mitigated) market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry, and that there is no opportunity for abusive transactions involving regulated affiliates of the seller. All of Calpine's Affiliates that own domestic power plants, except for those power plants that are QFs under PURPA or are located in ERCOT, as well as its power marketing companies are currently authorized by FERC to make wholesale sales of power at market-based rates. This authorization could possibly be revoked for any of these companies for a variety of reasons.

The EPAct 2005 promulgated PUHCA 2005, which repealed PUHCA of 1935 effective February 8, 2006. Under PUHCA 2005, certain companies in Calpine's ownership structure may be considered "holding companies" as defined in PUHCA 2005 by virtue of their control of the outstanding voting securities of companies that own or operate facilities used for the generation of electric energy for sale or

that are themselves holding companies. Under PUHCA 2005, such holding companies arc subject to certain FERC rights of access to eompanies' books and records that are determined by FERC to be relevant to the companies' respective FERC-jurisdictional rates. Although under PUHCA 2005 Calpine is considered a holding company, it is exempt from the new books and records provisions because it is a holding company solely owning one or more QFs, EWGs, or foreign utility companies. However, if any single Calpine Entity were to lose its status as a QF, EWG, or foreign utility company, then Calpine and its holding company subsidiaries would be subject to the books and reeords access requirement, and certain Calpine affiliates would be subject to FERC's accounting, record-retention, and reporting requirements.

Prior to its amendment by EPAet 2005 and the new regulations adopted by FERC, PURPA provided certain incentives for electric generators whose projects satisfy FERC's criteria for QF status. EPAct 2005 and FERC's implementing regulations have eliminated certain benefits of QF status, such as the exemption from sections 205 and 206 of the FPA for a QF's wholesale sales of power made at market-based rates. Under FERC's new regulations, Calpine's QFs will have to obtain market-based rate authorization for wholesale sales that are made pursuant to a contract exeeuted after March 17, 2006, and not under a state regulatory authority's implementation of section 210 of PURPA. In addition, new cogeneration QFs will be required to demonstrate that their thermal, chemical, and meehanical output will be used fundamentally for industrial, commercial, residential, or institutional purposes.

EPAct 2005 also amends PURPA to eliminate, on a prospective basis, electric utilities' requirement under section 210 of PURPA to purchase power from QFs at the utility's "avoided cost," to the extent FERC determines that sueh QFs have aceess to a competitive wholesale electricity market. This amendment to PURPA does not change a utility's obligation to purchase power at the rates and terms set forth in pre-existing QF power purchase agreements.

EPAet 2005's amendments to PURPA also include eertain new QF benefits, such as the elimination of thc electric utility ownership limitations on QFs. FERC also has exempted QFs from PUHCA 2005. QFs are still exempt from many provisions of the FPA and most state laws and regulations relating to financial, organization, and rate regulation of electrie utilities.

(ii) State Regulation

Calpine is also subject to stringent regulation at the state level. Historically, state public utility commissions ("PUCs") had broad authority to rcgulate the rates and financial activities of electric utilities operating in their states, promulgate regulation for implementation of PURPA, and oversee the siting, permitting, and construction of electric generating facilities. Power sales agreements with independent electrieity producers, such as EWGs, are potentially under the regulatory purview of PUCs and, in partieular, the process by which the utility has entered into thc power sales agreements is under the purview of PUCs. In addition, retail sales of electricity or thermal energy by an independent power producer may be subject to PUC regulation depending on state law. Independent power producers that are not QFs under PURPA or EWGs pursuant to the Energy Policy Act of 1992 are considered to be public utilities in many states and are subject to broad regulation by a PUC, ranging from the requirement to obtain a certificate of public convenience and necessity to regulation of organizational, accounting, financial, and other corporate matters. Beeause all of Calpine's affiliates are either QFs or EWGs, none of its affiliates are currently subject to such regulations.

b. Environmental Rcgulation

Calpine is also subject to extensive federal, statc, and local laws and regulations adopted for thc protection of the environment. Applicable environmental laws and regulations primarily involve the

discharge of emissions into the water and air and the use of water, but also include wetlands preservation, endangered species, hazardous materials handling and disposal, waste disposal, and noise regulations. These laws and regulations often require a lengthy proeess of obtaining licenses, permits, and approvals from federal, state, and local agencies.

Noncompliance with environmental laws and regulations can result in the imposition of civil or criminal fines or penalties. In some instances, environmental laws also may impose clean-up or other remedial obligations in the event of a rclease of pollutants or eontaminants into the environment. The Clean Air Act, The Federal Clean Water Act and The Safe Drinking Water Act are among the more significant federal environmental laws as they apply to Calpine. In most cascs, analogous state laws also exist that may impose similar, and in some cases more stringent, requirements on Calpine as those discusscd below.

(i) *Clean Air Act.* The Clean Air Act provides for the regulation of emissions of air pollutants from certain facilities and operations. As originally enacted, the Clean Air Act sets guidelines for emissions standards for major pollutants (*i.e.*, SO_2 and NO_x) from ncwly built sources. In late 1990, Congress passed the Clean Air Act Amcndments, which attempt to reduce emissions from existing sources, particularly previously exempted older power plants.

(ii) *Clean Water Act.* The Federal Clean Water Act establishes rules regulating the discharge of pollutants into waters of the United States. Calpine is required to obtain discharge permits for wastewater and runoff from certain of its facilities. It is Calpine's view that, with respect to its geothermal operations, it is exempt from newly promulgatcd federal storm water requircments. Calpine is required to maintain a spill prevention control and countermeasure plan with respeet to certain of its oil and natural gas facilities.

(iii) *Safe Drinking Water Act.* Part C of the Safe Drinking Water Aet mandates an underground injection control program that regulates the disposal of wastes, which is uscd for oil, natural gas, and geothermal production activities by means of deep well injection. Deep well injection is a common method of disposing of saltwater, produced water, and other oil and natural gas wastes. With the passage of EPAct 2005, oil, natural gas, and geothermal production activities are exempt from the underground injection control program under the Safe Drinking Water Act.

6. Additional Information

For additional information about the Debtors' business operations, please refer to Calpine's Annual Report on Form 10-K for the fiscal year ended December 31, 2006, and Calpine's Quarterly Reports on Form 10-Q for the first quarter of 2007 ending March 31, 2007, and any other recent Calpine report to the Securities and Exchange Commission. These filings arc available by visiting the Securitics and Exchange Commission's website at http://www.sec.gov or the Debtors' website at http://www.calpine.com.

B. The Debtors' Prepetition Capital Structure

1. Calpine

a. Summary

As of the Petition Date, Calpine Corporation had four major categories of funded debt: the First Lien Debt (as defined below); the Second Lien Debt (as defined below); the Senior Notes; and the ULC Notes (consisting of the ULC1 Notes, the ULC2 8.375% Senior Notes Due 2008, and the ULC2 8.875% Senior Notes Due 2011). In addition, Calpine Corporation was obligated under certain issued and drawn letters of credit. Finally, as of March 31, 2007, Calpine had 462,686,670 shares of Old Calpine Common Stock outstanding.

b. The First Lien Debt

The first lien debt was composed of the $785,000,000 9.625% First Priority Senior Secured Notes due 2014 (the "First Lien Debt"), issued by Calpine pursuant to that certain Indenture, dated as of September 30, 2004 (the "First Lien Indenture"), between Calpine and Wilmington Trust Company, as trustee (the "First Lien Trustee"). As of the Petition Date, the total principal amount outstanding under the First Lien Debt was approximately $646.1 million. The First Lien Debt was allegedly secured by a first priority Lien on substantially all of the properties and assets owned by Calpine directly. As described in further detail in Article III.D.2, Calpine repaid the entire outstanding principal of the First Lien Debt in June 2006. Litigation regarding the noteholders' Claim to a "makewhole" premium in connection with the Debtors' repayment of the First Lien Debt and the validity of the alleged first priority Lien is also described in further detail in Article III.D.2.

c. The Second Lien Debt

Calpine's second lien debt is composed of (collectively, the "Second Lien Debt"):

(i) the $500,000,000 (original principal amount) Second Priority Senior Secured Floating Rate Notes due 2007;

(ii) the $1,150,000,000 (original principal amount) 8.50% Second Priority Senior Secured Notes due 2010;

(iii) the $900,000,000 (original principal amount) 8.75% Second Priority Senior Secured Notes due 2013;

(iv) the $400,000,000 (original principal amount) 9.875% Second Priority Senior Secured Notes due 2011; and

(v) the $750,000,000 Second Priority Senior Secured Term Loan due 2007.

As of the Petition Date, the total principal amount outstanding under the Second Lien Debt was approximately $3.672 billion. The Second Lien Debt is secured by a second priority Lien on substantially all of the properties and assets owned by Calpine directly, and through the Replacement DIP Facility (as defined below), Liens on all other assets junior to existing permitted Liens. The Debtors have made certain interest payments on the Second Lien Debt during the Chapter 11 Cases, pursuant to adequate protection agreements made between the Debtors and the Second Lien Debt noteholders, as described in

further detail in Article III.B.2. The Debtors have not repaid any of the outstanding principal under the Second Lien Debt.

d. Senior Notes

As of November 30, 2005, Calpine was obligated in the aggregate principal amount of approximately $786.06 million on the following issuances of unsecured notes that are the beneficiaries of certain contractual subordination provisions with respect to other issuances of unsecured notes:

(i) the $180,000,000 (original principal amount) 10.5% Senior Notes due 2006;

(ii) the $275,000,000 (original principal amount) 8.75% Senior Notes due 2007;

(iii) the $400,000,000 (original principal amount) 7.875% Senior Notes due 2008;

(iv) the $250,000,000 (original principal amount) 7.625% Senior Notes due 2006; and

(v) the $350,000,000 (original principal amount) 7.75% Senior Notes due 2009.

e. Unsecured Notes

In addition, as of November 30, 2005, Calpine was obligated in the aggregate principal amount of approximately $2.917 billion on the following issuances of unsecured notes:

(i) the $750 million (original principal amount) 8.625% Senior Notes due 2010;

(ii) the $736 million (original principal amount) 6.00% Contingent Convertible Notes due 2014;

(iii) the $650 million (original principal amount) 7.75% Contingent Convertible Notes due 2015;

(iv) the $900 million (original principal amount) 4.75% Contingent Convertible Senior Notes due 2023;

(v) the $2.0 billion (original principal amount) 8.5% Senior Notes due 2011; and

(vi) the $1.2 billion (original principal amount) 4% Convertible Senior Notes due 2006.

The $650 million 7.75% Contingent Convertible Notes due 2015 are subordinated to the five series of Senior Notes described in Article II.B.d above by the terms of the indentures under which such Senior Notes were issued. The Debtors have not paid any interest or outstanding principal on any of the unsecured Senior Notes since the Petition Date.

f. ULC Notes

In addition to the above issuanees, Calpine issued certain notes to secure funding for its Canadian operations and general corporate purposes through ULC1 and ULC2, shell "unlimited liability" subsidiaries formed in Canada. These ULC Notes are allegedly guaranteed by Calpine pursuant to the relevant trust indentures. The status of the ULC Notes is as follows:

(i) Calpine allegedly guaranteed $2,030 million 8.5% Senior Notes due May 1, 2008 (original principal amount), of which $1,500 million were issued on April 25, 2001 and $530 million were issued on October 16, 2001. Between 2003 and 2005, Calpine repurchased certain of these 8.5% Senior Notes. As of the Petition Date, (A) approximately $134 million principal amount of these repurchased Senior Notes were held by Calpine, (B) approximately $10 million principal amount of these repurchased Senior Notes were held by Quintana Canada Holdings, LLC ("QCH"), a Debtor, (C) approximately $360 million principal amount of these repurchased Senior Notes were held by CCRC, and (D) approximately $103.3 million of these repurchased Senior Notes were formally cancelled by Calpine pursuant to the terms of the relevant trust indenture.

(ii) The entire principal amount of the C$200 million 8.75% Senior Notes due October 15, 2007 was outstanding as of the Petition Date and was held in its entirety by the public.

(iii) Calpine allegedly guaranteed the £200 million 8.875% Senior Notes due 2011, most of which are publicly held. However, approximately £78.6 million prineipal amount of these 8.875% Senior Notes were repurchased by Calpine in 2003, and, as of the Petition Date, were held by Saltend, L.P., one of Calpine's Canadian subsidiaries.

(iv) Calpine allegedly guaranteed the €175 million 8.375% Senior Notes due 2008, most of which are publicly held. However, approximately €57.6 million principal amount of these 8.375% Senior Notes were repurchased by Calpine in 2003 and 2004 and as of the Petition Date were held by Saltend, L.P., one of Calpine's Canadian subsidiaries.

Certain of these ULC Notes are the subject of a settlement between Calpine and Calpine's Canadian subsidiaries and affiliates described in further detail in Article III.D.6. The Debtors have not paid any interest or outstanding prineipal on any of the ULC Notes since the Petition Date.

g. Letter of Credit Facilities

As of November 30, 2005, approximately $185.23 million in letters of credit had been issued on Calpine's behalf pursuant to that certain Letter of Credit Agreement dated as of September 30, 2004, between Calpine and Bayerische Landesbank, acting through its Cayman Islands Branch. An approximately $36.33 million letter of credit had been drawn, resulting in the aggregate outstanding lctters of credit issued on Calpine's behalf to be approximately $147.43 million. The lctter of credit facility is secured by Cash on deposit in a cash collateral account, which has bcen reduced to approximately $147.54 million because of a draw corresponding to the drawn lctter of credit.

On December 7, 2005, a $78.35 million standby letter of credit expiring December 20, 2005 issued on Calpine's behalf pursuant to that certain Amended and Restated Letter of Credit and Reimbursement Agreement dated as of September 15, 2004, between Calpine and Credit Suisse First Boston was drawn in the amount of $74.14 million. However, the letter of eredit facility is secured solely by a back-up letter of credit issued by Bayerische Landesbank, on which Credit Suisse First Boston has previously drawn to the extent permitted, and is not guaranteed by any of Calpine's affiliates.

h. Old Calpine Common Stock

As of Mareh 31, 2007, Calpine had 462,686,670 shares of Old Calpine Common Stock outstanding, after accounting for certain shares issued under that certain Share Lending Agreement, dated as of September 28, 2004, among Calpine, as Lender, Deutsche Bank AG London, as Borrower, through Deutsche Bank Securities Inc., as agent for the Borrower, and Deutsche Bank Securities Inc., in its capacity as Collateral Agent and Securities Intermediary (the "Share Lending Agreement").

2. The Project Level Debt

Certain of Calpine's Debtor affiliates operate projects (collectively, the "Project Debtors") with their own secured finaneing or leasehold obligations. Thesc debt obligations are described in further detail below.

a. Secured Project Debt

(i) The CalGen Secured Debt

The primary prepetition obligations of Calpine Generating Company, LLC ("CalGen") arose under a series of first, second and third lien financings and a revolving loan (the "CalGen Secured Debt"), which were secured by substantially all of the assets of CalGen and its domestic subsidiaries without recourse to Calpine or its other subsidiaries. As of the Petition Date, the total principal amount outstanding under the CalGen Secured Debt was approximately $2.405 billion.

(a) *The CalGen First Lien Debt.* CalGen's first lien debt was composed of (1) the $235,000,000 First Priority Secured Floating Rate Notes due 2009, (2) the $600,000,000 First Priority Secured Institutional Term Loans due 2009, and (3) the $200,000,000 First Priority Revolving Loans, dated as of March 23, 2004. The CalGen first lien dcbt was secured by a first Lien on substantially all of the assets of CalGen and its domestic subsidiaries.

(b) *The CalGen Second Lien Debt.* CalGen's second lien debt was composed of (1) the $640,000,000 Second Priority Secured Floating Rate Notes due 2010 and (2) the $100,000,000 Second Priority Secured Institutional Term Loans due 2010, issued by CalGen pursuant to that certain Credit and Guarantee Agreement, dated as of March 23, 2004. The CalGen second lien debt was secured by a second Lien on substantially all of the assets of CalGen and its domestic subsidiaries.

(c) *The CalGen Third Lien Debt.* CalGen's third lien debt was composed of (1) the $680,000,000 Third Priority Secured Floating Rate Notes due 2011 and (2) the $150,000,000 11.5% Third

Priority Secured Notes due 2011. The CalGen third lien debt was secured by a third Lien on substantially all of the assets of CalGen and its domestic subsidiaries.

During the Chapter 11 Cases, the Debtors made certain interest payments on the CalGen Secured Debt, pursuant to adequate protection agreements made between the Debtors and the holders of the CalGen Secured Debt (the "CalGen Lenders"), as described in further detail in Article III.B.2. Further, in March 2007, the Debtors used proceeds from the Replacement DIP Facility (as defined below) and CalGen Cash on hand to repay all of the approximately $2.5 billion of the outstanding principal owed under the CalGen Secured Debt, as described in further detail in Article III.D.3 below. Litigation regarding the CalGen Lenders' Claim to a "makewhole" premium and other damages in connection with the Debtors' repayment of the CalGen Secured Debt is described in further detail in Article III.D.3.

(ii) The Bethpage Project Debt

Bethpage Energy Center 3, LLC ("BEC3") owns a 79.9-MW combined cycle generating facility located in Hicksville, New York. As of the Petition Date, BEC3 owed approximately $121.1 million under first and second priority lien term loans, which are secured by first and second priority liens, respectively, on all of the assets of BEC3, including all real and personal property and all revenues and accounts pursuant to various mortgages and security agreements and all of the ownership interest of Calpine Eastern Corporation in BEC3 pledged pursuant to certain pledge agreements.

(iii) The Aries Project Debt

MEP Pleasant Hill, LLC ("MEPPH") owned the Aries facility, an approximately 590 MW dispatchable, combined cycle natural gas-fired generating facility located in Cass County, Missouri. To repay certain construction loans related to the Aries facility, MEPPH entered into certain term loan agreements with DZ Bank, AG, Deutsche Zentral-Genossenschaftsbank, Frankfurt AM Main, New York Bank and certain other lenders. The term loans were secured by all of MEPPH's assets, including the Aries facility as well as CPN Pleasant Hill, LLC's ownership interests in MEPPH. As of the Petition Date, MEPPH owed approximately $160 million under the term loans. As described in further detail in Article III.D.1, the Debtors sold the Aries facility in January 2007, and the debt associated with the facility was retired at that time.

b. <u>Project Leases and Related Obligations</u>

(i) Summary of Project Leases and Related Obligations

Certain of the Debtors' project affiliates are parties to leveraged lease transactions under which each has secured property and other assets to operate their respective power generation facilities. These leveraged lease transactions are described in further detail below.

(ii) The KIAC Project

KIAC Partners ("KIAC") leases a central heating and refrigeration plant, thermal distribution system, and natural gas-fired cogeneration plant at John F. Kennedy International Airport in Queens, New York. The primary prepetition obligations of KIAC arise under (i) that certain Guaranty, dated as of May 1, 1996, in favor of the Bank of New York (as successor to the United States Trust Company of New York) as Trustee, pursuant to which KIAC guaranteed $250,000,000 of special project bonds issued to finance the construction, operation, and maintenance of the facility and (ii) under that certain Agreement of Lease, dated as of April 28, 1993, pursuant to which KIAC leases the facility from the Port Authority

or New York and New Jersey. As of the Petition Date, approximately $204.20 million of the KIAC special projeet bonds were outstanding.

KIAC's obligations under the lease and the guaranty are secured on a first priority basis by substantially all of the property of KIAC, including KIAC's interests under the lease.

(iii) The Nissequogue Cogen Project

Nissequogue Cogen Partners ("NCP") leases an approximately forty MW cogeneration power plant located on the campus of the State University of New York at Stony Brook. The primary prepetition obligations of NCP arise under (i) that certain Guaranty, dated as of November 1, 1998, by NCP in favor of the Bank of New York (as sueeessor to the United States Trust Company of New York) as trustee, pursuant to which NCP guaranteed payment of $74,200,000 of Industrial Revenue Bonds issued to finance the construction, operation and maintenance of the NCP Facility and (ii) that certain Amended and Restated Lease Agreement, dated as of November 1, 1998, pursuant to which NCP leases the facility from the Suffolk County Industrial Development Agency. As of the Petition Date, approximately $71.70 million of the industrial revenue bonds were outstanding.

NCP's obligations under the guaranty and the lease are secured on a first priority basis by substantially all of the property of NCP, ineluding NCP's interests under the lease.

(iv) The Watsonville Project

Calpine Monterey Cogeneration, Inc. ("CMC") leases the Watsonville project, a 28.5 MW combined cycle cogeneration facility located in Santa Cruz County, California, from U.S. Bank National Association (as successor in interest to State Street Bank and Trust Company of California, N.A.) pursuant to that certain Watsonville Facility Leasc, dated as of June 22, 1995, and other contemporaneous agreements.

In addition to the remedies for default under thc lease, CMC's obligations under the lease are secured by revenue from the facility and CMC's interests in certain aceounts, CMC's interest in the Watsonville facility and real estate, and shares of common stock of CMC pledged by Calpine under a stoek pledge agreement and a gas sale and purehase agreemcnt.

(v) The Greenleaf Project

Calpine Greenleaf, Inc., ("Greenleaf"), leases two cogeneration projects, 49.2 MW and 49.5 MW, respeetively, and certain related equipment located in Sutter County, California. The Greenleaf facilities are leased by Greenleaf pursuant to that certain Facility Lease Agreement, dated as of August 10, 1998, between U.S. Bank, National Association and Greenleaf, as amendcd, and other contemporaneous agreements.

In addition to the remedies for default under the lease, Greenleaf's obligations are secured by pledges of all Cash and receivables of the Greenleaf faeilities, all equipment, general intangibles, and rights under certain project agreements, and all rights under real property leases, improvements, easements and all equipment. Certain of Greenleaf's obligations under the lease are also guaranteed by Calpine. Calpine and Calpine Fuels Corporation eaeh have pledged certain guarantees related to other Greenleaf obligations.

(vi) The Gilroy Cogen Project

Calpine Gilroy Cogen, L.P. ("Gilroy Cogen") owns a gas-fired cogeneration facility and related equipment located in Gilroy, California. Pursuant to a certain purchase agreement (the "Gilroy Purchase Agreement"), in October 2003, Calpine sold certain PG&E receivables to SPCP Group, LLC, MacKay Shields LLC, Special Situations Investing Group, Inc., Drawbridge Special Opportunities Fund LP, DB Special Opportunities LLC, and Canpartners Investments IV, LLC. The net proceeds received by Calpine under the Gilroy Purchase Agreement was $133.4 million.

Under the terms of the Gilroy Purchase Agreement, Calpine and Gilroy Cogen have continuing obligations, including certain indemnity obligations for all losses arising from, among other things, breach of representations or warranties in the Gilroy Purchase Agreement, failure to perform any covenant or obligation under the Gilroy Purchase Agreement, and any setoff or reduction in payment by PG&E. The maximum liability of Calpine and Gilroy Cogen under the Gilroy Purchase Agreement is subject to a cap of approximately $141.7 million as of November 30, 2005.

Calpine's obligations under the Gilroy Purchase Agreement have been guaranteed by Gilroy Cogen. In addition, as security for Gilroy Cogen's obligations under the Gilroy Purchase Agreement and the guaranty, Gilroy Cogen has pledged certain of its project assets and an intercompany demand note in the amount of $80.0 million payable by Calpine to Gilroy Cogen.

(vii) The Geysers

Geysers Power Company, LLC ("GPC") leased fifteen geothermal electric generating facilities (collectively, the "Geysers Facilities") located in the Sonoma and Lake Counties, California from Geysers Statutory Trust, a Connecticut statutory trust formerly controlled by Steam Heat, LLC, a subsidiary of Verizon Capital Corporation, pursuant to that certain Third Amended and Restated Facility Lease Agreement, dated as of May 7, 1999.

Through a series of transactions ending in the late 1990s, GPC acquired The Geysers, as well as rights to the real estate upon which The Geysers are located. GPS and Silverado Geothermal Resources, an affiliate, also acquired certain related mineral and other real estate rights which produce steam for the operation of The Geysers. Between 1999 and 2001, GPC entered into four leveraged sale-leaseback transactions pursuant to which GPC sold The Geysers to the Geysers Statutory Trust, which then leased the facilities back to GPC.

The Geysers Statutory Trust initially had financed the purchase of The Geysers through the issuance of notes and, on the Petition Date, was indebted to those lenders in an amount of approximately $103.9 million. GPC's obligations under the lease transactions were secured by the limited liability company interests of GPC's direct parents, Geysers Power Company I and Geysers Power II Company, in GPC. Further, Silverado's sole shareholder pledged all of its stock in Silverado to GPC. To provide collateral for the notes, the Geysers Statutory Trust pledged its interests in The Geysers, as well as its interest in the foregoing equity pledges, to a trustee for the benefit of the lenders. Calpine also guaranteed payment of certain related obligations under the lease transactions.

As described in further detail in Article III.B.1.a, the Debtors unwound The Geysers leverage lease transactions in order to unencumber The Geysers for use as collateral in obtaining debtor-in-possession financing.

(viii) The Agnews Project

O.L.S. Energy-Agnews, Inc. ("Agnews") leases a 28.5 MW combined cycle cogeneration facility located in Santa Clara County, California. The Agnews facility is leased from The Bank of New York Trust Company, NA. pursuant to that certain Facility Lease Agreement, dated as of December 1, 1990. Pursuant to that certain Guaranty, dated as of December 1, 1990, Calpine guaranteed the obligations of Agnews under the lease.

In addition to the remedies for default under the lease, Agnews' obligations under the lease are secured by Agnews' rights under certain project documents, the stock of Agnews pledged by its parent Calpine Agnews, Inc. and Agnews' interest in the rent collateral account.

(ix) The Hidalgo Project

Calpine Hidalgo Energy Center, L.P. ("Hidalgo") owns a 78.5% interest in the 485 MW gas-fired combined-cycle power plant under construction located in Edinburg, Texas. Hidalgo purchased its interest in the facility from Duke Energy North America for $235 million, which included a Cash payment of $134 million and the assumption of certain liabilities, including obligations under a sale-leaseback of certain electrie generating equipment with Industrial Development Corporation of the City of Edinburg, Texas. Duke Capital Corporation guaranteed Hidalgo's obligations under the lease, and Calpine Corporation agreed, among other things, to indemnify Duke Capital Corporation for any losses it incurs under the guarantees. Construction of the facility began in February 1999, and commercial operation was achieved in June 2000. As of March 2007, Hidalgo owed approximately $100.2 million under the capital lease.

(x) The Rumford-Tiverton Projects

Tiverton Power Associates Limited Partnership ("Tiverton") leased a 265 MW gas-fired combined cycle merchant power plant located in Tiverton, Rhode Island from PMCC Calpine New England Investment LLC pursuant to that certain Facility Lease Agreement, dated as of December 19, 2000. Rumford Power Associates Limited Partnership ("Rumford") leased a 265 MW gas-fired combined cycle merchant power plant located in Rumford, Maine from PMCC Calpine New England Investment LLC pursuant to that certain Facility Lease Agreement dated as of December 19, 2000.

In addition to the remedies for default under the leases, the Rumford and Tiverton's obligations under their respective leases were secured by an equity collateral account, which was pledged as security for Calpine's performance of its obligations as guarantor to pay the equity portion of the termination value. As described in further detail in Article III.D.1 below, the Rumford and Tiverton facilities were turned over to a receiver in June 2006, and the debt associated with the facilities was retired at that time.

(xi) The South Point Project

South Point Energy Center, LLC ("South Point") leases a 553 MW gas-fired combined cycle power plant located near Bullhead, Arizona. The South Point facility is owned by four separate Entities, South Point OL-1, LLC, South Point OL-2, LLC, South Point OL-3, LLC and South Point OL-4, LLC, each of which are affiliates of CIT Credit Group USA, Inc. ("CIT"), with each owning an undivided 25% interest in the faeility. South Point leascs the South Point facility from the owner-lessors pursuant to four separate Facility Lease Agreements, each dated as of October 18, 2001.

In addition to the remedies for default under the leases, South Point's obligations are secured by pledges of the ownership interest in South Point pursuant to four separate Pledge and Security

Agreements, among South Point Holdings, LLC, Calpine Corporation, South Point and each of the owner-lessors. Certain of South Point's obligations under the leases are also guaranteed by Calpine. The obligations of South Point Facility Lessee are not secured by any collateral other than the ownership interest in the South Point, and related rights thereto, pledged to the owner-lessors.

(xii) The Broad River Project

Broad River Energy LLC ("Broad River") leases a 866 MW gas-fired combined cycle power plant located near Gaffney, South Carolina. The Broad River facility is owned by four separate Entities, Broad River OL-1, LLC, Broad River OL-2, LLC, Broad River OL-3, LLC and Broad River OL-4, LLC, each of which are affiliates of CIT, with each owning an undivided 25% interest in the facility. Broad River leases the Broad River facility from the owner-lessors pursuant to four separate Facility Lease Agreements, each dated as of October 18, 2001.

In addition to the remedies for default under the leases, Broad River's obligations are secured by pledges of the ownership interest in Broad River pursuant to four separate Pledge and Security Agreements among Broad River Holdings, LLC, Calpine Corporation, Broad River and each of the owner-lessors. Certain of Broad River's obligations under the leases are also guaranteed by Calpine. The obligations of Broad River are not secured by any collateral other than the ownership interest in Broad River, and related rights thereto, pledged to the owner-lessors.

(xiii) The RockGen Project

RockGen Energy LLC ("RockGen") leases a 509 MW gas-fired combined cycle power plant located near Christiana, Wisconsin. The RockGen facility is owned by four separate Entities, RockGen OL-1, LLC, RockGen OL-2, LLC, RockGen OL-3, LLC and RockGen OL-4, LLC, each of which are affiliates of CIT, with each owning an undivided 25% interest in the facility. RockGen leases the RockGen facility from the owner-lessors pursuant to four separate Facility Lease Agreements, each dated as of October 18, 2001.

In addition to the remedies for default under the leases, RockGen's obligations are secured by pledges of the ownership interest in RockGen pursuant to four separate Pledge and Security Agreements, among Calpine Northbrook Project Holdings, LLC, Calpine Corporation, RockGen and each of the owner-lessors. Certain of RockGen's obligations under the leases are also guaranteed by Calpine. The obligations of RockGen are not secured by any collateral other than the ownership interest in the RockGen, and related rights thereto, pledged to the owner-lessors. As described in further detail in Article III.D.1, the Debtors and CIT entered into a forbearanee agreement in November 2006, under which CIT agreed to forbear from exercising remedies against, among other parties, the Debtors, and further agreed to market the facility for sale in an attempt to maximize its value. CIT continues to market the facility.

c. <u>Non-Debtor Project Debt</u>

Calpine's asset portfolio includes interests in certain non-Debtor Affiliate projects, some of whieh have one or more forms of project-level financing including secured debt, preferred interests, notes payable, and capital lease obligations totaling net of project-level Cash, approximately $4.06 billion before taking into account any Cash at such non-Debtor Affiliates. In general, the financing pertaining to each of these non-Debtor Affiliates is not affected by the Chapter 11 Cases. Moreover, Article VIII.A of the Plan provides that any defaults caused by the Debtors' filing of the Chapter 11 Cases will be deemed Cured as of the Effective Date. The Valuation Analysis and the Liquidation Analysis in Article V of the

Disclosure Statement takes into account the Debtors' interests in these non-Debtor Affiliates, as well as these Affiliates' liabilities.

C. Management of the Debtors

The management team of Calpine is composed of highly capable professionals with substantial experienee in the energy industry or in the management of large companies. Information regarding the executive officers of the Debtors is as follows:

Name	Age	Position
Robert P. May	58	Chief Executive Officer
Charles B. Clark, Jr.	59	Senior Vice President and Chief Accounting Officcr
Lisa Donahue	42	Senior Vice President and Chicf Financial Officer
Gregory L. Doody	42	Executive Vicc Prcsident, General Counsel, and Secretary
Robert E. Fishman	55	Executive Vice President, Power Operations
Gary Germeroth	49	Executive Vice President, Chief Risk Officer
Thomas N. May	45	Executive Vice President, Commercial Operations

Robert P. May has served as Chief Executive Officer and a director of Calpine since December 2005. Mr. May served as Intcrim President and Chief Executive Officer of Charter Communications, Inc. from January 2005 to August 2005. He served on the Board of Directors of HealthSouth Corporation from October 2002 to October 2005 and as its Chairman of the Board from July 2004 to October 2005. From March 2003 to May 2004, he served as HealthSouth's Interim Chief Executive Officer, and from August 2003 to January 2004, he served as Interim President of its outpatient and diagnostic division. Since March 2001, Mr. May has been a private investor and principal of RPM Systems, which provides strategic business cousulting services. From March 1999 to March 2001, Mr. May served on the Board of Directors and was Chief Executive of PNV Inc., a national telecommunications company. Mr. May was Chief Operating Officer and a director of Cablevisions Systems Corp., from October 1996 to February 1998. He held several senior executive positions with Federal Express Corporation, including President, Business Logistics Services, from 1973 to 1993. Mr. May was educated at Curry College and Boston College and attended Harvard Business School's Program for Management Development. Mr. May also serves as a director of Charter Communications, Inc. and on the advisory board of Deutsche Bank America. Mr. May is a member of the Executive Committee.

Charles B. Clark, Jr. has served as Senior Vice President and Chief Accounting Officer since Decembcr 2006 and his responsibilities include internal and external financial reporting, both Securities and Exchange Commission and in the Chapter 11 Cases; and special projects. He served previously as Calpine's Senior Vice President since Septembcr 2001 and Corporate Controller since May 1999. He was the Director of Business Services for Calpine's Geysers operations from February 1999 to April 1999. He also served as a Vice President of Calpine from May 1999 until September 2001. Prior to joining Calpine, Mr. Clark served as the Chief Financial Officer of Hobbs Group, LLC from March 1998 to November 1998. Mr. Clark also served as Senior Vice President, Finance and Administration, of CNF Industries, Inc. from February 1997 to February 1998. He served as Vice President and Chief Financial Officer of Century Contractors West, Inc. from May 1988 to January 1997. Mr. Clark obtained a Bachelor of Science degree in Mathematics from Duke University in 1969 and a Master of Business Administration degree, with a concentration in Finance, from Harvard Graduate School of Business Administration in 1976.

Lisa Donahue has served as Senior Vice President and Chief Financial Officer since November 2006. She is a Managing Director of AlixPartners and its affiliate AP Services. AP Services has been retained by Calpine in connection with its chapter 11 restructuring. Ms. Donahue, who has been